STATE OF KANSAS
BEFORE THE STATE COPRPORATION COMMISSION

Before Commissioners: John Wine, Chair
Cynthia L. Claus
Brian J. Moline

WESTERN RESOURCES, INC.)
)
and)
)
KANSAS GAS AND ELECTRIC)
COMPANY, INC.)

Docket No. Ol-WRSE-436-RTS

DIRECT TESTIMONY OF EDWARD C. BODMER

Section I: Introduction

Q. What is your name and address?

A. My name is Edward C. Bodmer and my address is 5951 Oakwood Drive, Lisle, Illinois 60532.

Q. Who has employed you to testify in this matter?

A. The City of Topeka, Kansas

Q. Please summarize your educational background.

A. I received a Bachelor of Science degree with honors in Finance from the University of Illinois in 1979 and a Master degree in Business Administration with honors from the University of Chicago in 1986. I have developed and taught specialized project finance, financial modeling, corporate finance, options pricing, and economics courses throughout the world. I am presently serving as an adjunct professor of economics at Lewis University, Romeoville, Illinois.

Q. What is your professional experience.

A. From 1979 to 1983 I worked as a financial analyst for the Illinois Commerce Commission. While employed with the Commission I was actively involved in a variety of regulatory matters involving the electric utility industry including the establishment of just and reasonable electric service rates. From 1986 to 1990 I was employed by the First National Bank of Chicago as vice president in charge of credit analysis of all energy loans, including transactions with electric and gas utility companies. Since 1991 I have provided consulting services on a variety of issues including issues related to forward market pricing, industry re-structuring, rate design, cost of service, resource planning and performance evaluation, deregulation of electric utility generation, divestiture of generating assets, allocation of decommissioning liabilities, and design of delivery service tariffs.

Q. Have you testified before regulatory bodies?

A. I have testified before regulatory bodies on a wide variety of subjects, including transition to de-regulation, performance-based regulation, revenue requirements, cost-of-service and rate design.

Section II:

<u>Purpose, Organization and Summary of Testimony</u>

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked to review the proposals made by Western Resources, Inc. and Kansas Gas and Electric Company ("Applicants" or "Company") for the purpose of determining whether the proposed ratemaking treatment for the three new combustion turbine units at the Gordon Evans Energy Center and the recently purchased capacity of the combined cycle plant, referred to as the "Stateline" facility, are just and reasonable (collectively referred to as "new plants."). I was asked to quantify adjustments to the proposed revenue requirements in the event I concluded the ratemaking treatment proposed by the Applicants was not reasonable.

Q. How is your testimony organized?

A. After summarizing my conclusions, I discuss KPL's rate increase proposal and divergent interests between ratepayers and shareholders. Next, I describe specific adjustments related to energy margin from the new units, depreciation expense, the cost of Gordon Evans, capital recovery changes for Stateline, and transmission costs. Finally, I discuss the impacts of KPL's proposal on generating markets and ratepayer costs of KPL's capacity sale to Empire.

Q. Please summarize your testimony?

A. The rate treatment KPL has proposed for the new Gordon Evans combustion turbine units and the new Stateline combined cycle plant is unfair to KPL's ratepayers. The Applicants proposed rate treatment burdens the ratepayers in the KPL service territory with all of the costs, but gives them few of the benefits associated with the operation of the new facilities. I have made various recommended adjustments to Applicants proposed revenue requirements in order to achieve equitable treatment for the ratepayers. These include adjustments to Applicants proposed depreciation of the Gordon Evans facilities, costs related to the fact that the facilities are dual fuel capacity and thus provide Western with more flexibility in making off system sales. In addition, I have made adjustments relating to the Gordon Evans ground lease expense and adjustments to reflect energy cost savings from running the Gordon Evans plant. Finally, I made adjustments to Applicants State Line proposal concerning the capital recovery period, transmission costs and accompanying energy savings. These adjustments decrease, by $23 million, the revenue requirements proposed by Applicants.

In summary, the rate application is unfair to KPL ratepayers because it does not provide benefits normally associated with the operation of generation facilities which would offset the hundreds of millions of dollars of construction costs. Under Applicants' proposal, the benefits would flow to the shareholders and not

the ratepayers. This is fundamentally unfair. The Applicants get the car while the ratepayers get the payments.

Section III:
Revenue Requirement Analvsis

Q. Please describe the State Line and the Gordon Evans facilities.

A. The first two Gordon Evans facilities that were placed in service last summer are General Electric combustion turbine generators, each of which has approximately 80 MW of output capacity (for a combined output capacity of approximately 160 MW) and may be powered by either natural gas or fuel oil. The third Gordon Evans facility, currently under construction and scheduled to be placed in service in June of this year, is a much larger General Electric combustion turbine generating unit with an output capacity of 154MW and it, too, may be powered by either oil or natural gas. All three of these facilities will be located in or near Colwich, Kansas -- approximately 20 miles northwest of Wichita.

The State Line facility is a combined cycle unit currently under construction in Southwestern Missouri near the Kansas border. Empire District owns 60% of the State Line facility and and the remaining 40% is owned by Westar Generating, Inc., a wholly-owned subsidiary of Western Resources. As a result of its ownership interest, Westar Generating, Inc. (Westar) is entitled to 200 MW of output capacity from the State Line facility, which is scheduled to be placed in service this summer. Western Resources has agreed to purchase the 200 MW of output capacity from Westar Generating, Inc. Applicants propose in this docket that KPL assume the full cost of this purchased power agreement as well as related costs such as transmission expenses.

Q. Do you agree with Western Resources that the costs associated with all four facilities should be placed in KPL's rate base?

A. It appears that the 154 MW Gordon Evans combustion turbine and the State Line combined cycle unit may have been planned as merchant plants for at least some period of time. As Dr. Pflaum more fully explains in his testimony, since Western's acquisition of an additional 514 MW of output capacity within about 12 months is not required to serve its native load in the immediate future, such excess capacity appears to be largely meant to serve the wholesale market. However, for purposes of this testimony, I assume that the costs of such capacity are potentially eligible for inclusion in KPL's rate base. Therefore, my analysis is confined to adjustments that I believe are necessary to ensure the fair, just and reasonable ratemaking treatment of acquiring this additional output capacity from the new Gordon Evans and State Line generating facilities.

Q. If the Commission allows Western Resources to include in its rate base the costs associated with its construction of new generating units at Gordon Evans and its purchase of output capacity from State Line, do you believe any adjustments are required to achieve fair, just and reasonable ratemaking treatment of these costs?

A. **Yes.**

Q. Would you please summarize these adjustments and explain the impact, if any, they have on the proposed rate increase for KPL?

A. Yes. If the Commission allows Western Resources to include the costs associated with the three Gordon Evans combustion turbines and the purchased output capacity from the new State Line combined cycle unit, revenue requirements should be reduced significantly.

The revenue requirement for the new Gordon Evans combustion turbine units of approximately $30 million proposed by KPL should instead be $24 million to

account for value realized by energy production of the plant, a more appropriate depreciation allowance for the units and other items. The Stateline plant revenue increase proposal of approximately $22.5 million should instead be $5.6 million to reflect energy production from the plant, fair treatment of transmission, and a capital recovery period that covers the life of the plant for ratemaking purposes. Therefore, the total revenue requirement of $52.5 million proposed by the Company for the new plants is reduced to $29.6 million.

Costs to KPL retail ratepayers for the new plants are significantly greater than they would be if KPL had not agreed five years ago to sell 162 MW of capacity from its Jeffrey energy Center to Empire Electric for a ten-year period beginning in June of 2000. Without the Empire capacity sale, revenue requirements for the new plants would be $11.2 million instead of $29.6 million. Therefore, KPL's sale of capacity to Empire increases revenue requirements by $18.4 million. The fact that I have not recommended an adjustment for this capacity sale to Empire helps illustrate the conservative nature of my recommendations.

Q. Would you please elaborate on the components of the adjustments to revenue requirements for the new Gordon Evans combustion turbine units and the purchased power contract from the Stateline plant included in method 1?

A. Schedule __ ECB-1 below illustrates the items that I have included in making adjustments that reduce KPL's proposed revenue requirement for the new plants. The adjustments shown on the exhibit assume KPL's proposed return on equity of 12.75%. If the return on equity is reduced, the revenue requirement would be lower. The table demonstrates that even after making adjustments, the Gordon Evans capacity is relatively expensive for KPL ratepayers on a $/kW/Year basis.

My rational for making adjustments summarized in Schedule __ ECB-1 to Gordon Evans includes:

The depreciation adjustment allocates the cost of the Gordon Evans

combustion turbine plants over a thirty-five year life rather than the 25 year life assumed by the Company. The longer life is consistent with the expected operating lives of existing combustion turbine plants owned by Western.

The adjustment that I label "Cost of Dual Fuel Capability" removes from rate base costs of the Gordon Evans plants that allow KPL increased flexibility in making more profitable off-system sales and/or reducing purchased power costs. Since shareholders rather than ratepayers receive benefits from these features of the plant, the cost should not be attributed to ratepayers.

The adjustments titled "energy value" reflect KPL's ability to sell additional power in wholesale markets and/or its ability to offset purchased power expenses through operation of the Gordon Evans plants. The adjustment for Phase 1 measures increased energy value for the portion of the test year that the plant was not in service while the adjustment for Phase 2 reflects a full year of energy value from increased off-system sales and/or reduced purchases. I have computed the energy value adjustments using actual wholesale market price data for the test year.

The adjustment titled "ground lease adjustment" accounts for the fact that if the present value of the ground lease payments made by KPL to KGE are included as a component of the capital cost of Gordon Evans, its cost ($449/KW for Phase 1 and $432.02/KW for Phase 2) is significantly greater than the cost of comparable units presented in KPL's case.

The adjustments for the Stateline purchased contract include:

The adjustment for transmission reduces increased transmission charges requested by the Company for the Stateline plant because: (1) there is no offset to wheeling revenues earned by the Company including wheeling revenues earned from the Empire sale; (2) the geographic location of the plant has benefits to KPL shareholders as well as costs; and (3) KPL could have sited the plant at a location that would not have resulted in the additional transmission costs.

The adjustment labeled “Levelization over Plant Life” reflects the impact of a lengthened thirty-five year time frame for levelizing capital costs rather than the seven year term proposed by the Company. This adjustment precludes ratepayers from being saddled with high capital costs when the plant is receiving regulated treatment in early years of its life and not receiving benefits of merchant profits in later years of the plant’s life. The adjustment also includes removal of the variable operation and maintenance costs associated with the plant because this cost is subsumed in the measurement of the energy value of the plant.

The adjustment titled “Energy Value” for the Stateline plant is computed using the same approach as the energy value adjustments for Gordon Evans.

Q. What is your conclusion with respect to the costs and benefits associated with KPL’s capacity sale of 162 MW from the Jeffrey Energy Center to Empire that began on June 1, 2000?

A. The sale of capacity made by KPL to Empire, which began almost precisely at the time the first two Gordon Evans units became operational, has some ratepayer benefits, but the costs to KPL retail ratepayers outweigh any benefits. If the Empire capacity sale had not been made, KPL would require less new capacity and the energy that the Company sells to Empire at the cost of burning coal could instead be sold in wholesale markets at much higher prices or used on-system.

Counterbalancing these costs are the demand charges received by KPL from June 1, 2000 to September 30, 2000, some of which are credited against KPL retail revenue requirements. I have evaluated costs and benefits of the Empire sale accounting for the benefits of the demand charge revenues as well as the opportunity costs of not making added sales at market prices. This analysis demonstrates that the opportunity costs of reduced off-system sales far exceed the benefits of demand charge credits to ratepayers. Stated somewhat differently, if retail ratepayers could have purchased capacity on the same terms as Empire purchased capacity from KPL, instead of incurring the costs KPL proposes for Gordon Evans as part of the rate increase proposal, ratepayers would be better off.

The fact that KPL sold capacity to Empire also means that the Company needs more capacity than it would have required had the sale not been made. This implies that some capacity of the Gordon Evans plant would not have been needed to meet the 12% capacity margin. Schedule __ECB-2 illustrates that revenue requirements would be $18.4 million lower without the Empire sale.

Section IV:

Overview of Western's Proposal to Increase Rates For Recovey of Costs Associated With The New Generating Plants

Q. Describe how the new plants affect the dollar level of KPL's rate increase proposal?

A. KPL has included the capital costs (return on rate base, depreciation and taxes) as well as additional inventory costs, operation and maintenance expenses and costs of a "ground lease agreement" with KGE for the Gordon Evans combustion turbines in its proposed revenue requirement. To reflect costs of the Stateline combined cycle plant, KPL requests that purchased power costs (made up of capital recovery, variable operation and maintenance and fixed operation and maintenance) as well as transmission costs under the SPP regional transmission tariff be included in retail rates. Assuming the rate of return on equity of 12.75%

proposed by KPL, the Gordon Evans revenue requirement is approximately $30 million and the Stateline revenue requirement is approximately $22.5 million. Two of the new Gordon Evans combustion turbine units (160 MW out of 3 14 MW) are included in the Company's cost of service at September 30, 2000. These two units are sometimes called "Phase 1" by the KPL witnesses. The Company makes a separate adjustment for the third Gordon Evans combustion turbine unit (154 MW) which KPL projects to be placed in service later this year. This unit is sometimes called "Phase 2" by the Company. The total proposed revenue requirement of $52.5 million for all three of the combustion turbine units and the Stateline combined cycle plant represents about 56% of KPL's total proposed revenue increase of $93.3 million.

Q. In its rate increase filing, did KPL recognize the fact that operation of the new units will allow the Company to avoid high cost purchased power and/or make additional off-system sales?

A. No. In its response to City of Topeka data request 35, the Company states that it has not performed an analysis of how the operation of the new units will affect the operation of other generating plants, the quantity of purchased power or the amount of off-system sales. Even though the Company's executive vice president, Mr. Thomas Greenan acknowledges that the new units may allow the KPL to make added off-system sales (Greenan Direct Test. page 15). KPL makes no dollar adjustment to benefits from operation of the plants in the case.

Q. How does KPL explain the need for capacity from the new units?

A. Western projects a capacity margin from estimated peak load requirements, generating capacity, firm sales and purchases and capacity sales and purchases. In this analysis KPL's sale to Empire of 162 MW reduces KPL's capacity margin by the same amount as if generating capacity were reduced by 162 MW. The table below illustrates capacity margins for KPL and KGE with and without capacity from the new units and with and without KPL's sale of 162 MW to Empire.

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Q. How has KPL allocated transmission wheeling costs and revenues between retail customers and other customers in its proposed rate increase?

A. The Company asks that retail ratepayers incur additional costs for transmission associated with the SPP regional transmission tariff but KPL gives ratepayers virtually no credit for substantial increased wheeling revenues that it has realized in the past few years. In developing retail revenue requirements, KPL allocates revenues, expenses and rate base to KCC jurisdictional operations and

"wholesale" operations. The wholesale category includes municipal and co-operative partial requirements customers who pay for power under tariffs regulated by FERC. KPL allocates revenues earned from transmission wheeling almost exclusively to wholesale operations even though wheeling revenues do not lower rates for FERC regulated municipal and cooperative customers.

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During the test year, KPL earned a return on equity of 18.5% on a company-wide basis before any allocations to retail operations or wholesale operations (based on a return on rate base of 13.05%). This 18.5% return on equity figure does not include income from "below the line" operations that KPL earns from its power marketing activities that supposedly do not involve the Company's own generating plants. After costs and revenues are allocated to retail customers, the "KCC" retail portion of the company earned a return on equity of 17.7% during the test period. On the other hand, in large part because of the manner in which KPL allocates transmission wheeling revenues and transmission costs, the rate of return on equity earned during the test period was 27.6% for the non-retail portion of the company. Had after-tax income from power marketing been "above the line", KPL's company-wide return on rate base would have been 13.70% and its return on equity would have been 19.84% in the test year.

When making adjustments to actual data, KPL adds a provision for transmission costs as a separate adjustment to retail rates. KPL categorizes this adjustment as part of the cost of the Stateline capacity. In other words, the Company proposes to increase retail rates in order to cover transmission wheeling charges it will pay to other parties. This means that at the end of the day, retail ratepayers not only do not receive credit for wheeling revenues received by KPL that result in high returns, but on top of that, they are asked to pay added wheeling costs.

Section V:

KPL and Ratepayer Interests With Respect to Rate Treatment of Capacity Additions

Q. Are divergent interests between shareholders and ratepayers significant with respect to ratemaking issues associated with the new plants in KPL's proposed rate increase?

A. Yes. Developing competitive wholesale markets, retention of profits from future incremental off-system sales, new frameworks from transmission pricing, elimination of the fuel adjustment clause and infrequent rate cases have changed the manner in which many rate case issues should be evaluated. All of these factors have an effect on allocation of economic resources between ratepayers and shareholders with respect to KPL's new plants. Therefore, before describing detailed adjustments to KPL's proposal in subsequent sections of the testimony, I provide an overview of differences in economic interests between KPL shareholders and ratepayers on issues of merchant versus regulated treatment, risk allocation of price fluctuations in energy markets, rate case timing, depreciation rates on generating plants, off-system sales and transmission tariffs.

Q. How has the advent of merchant plant development affected ratepayer and shareholder incentives with respect to including the capital costs of new plants in revenue requirements?

A. Merchant developers construct new plants through assessing potential profit from selling power at market-clearing wholesale power prices rather than charging regulated rates or receiving an assured revenue stream through long-term purchase power agreements. If developers of merchant plants believe they can earn more than their cost of capital, then they will consider construction of new plants. The type of plant a merchant developer constructs (for example, a combined cycle plant versus a combustion turbine plant), the geographic location of a merchant plant, and added flexibility features of a merchant plant (such as

dual fuel capability) depend on expected profit from the plant. The profit from the type of plant, the geographic location of the plant and the features of the plant imply, in theory, that the most economically efficient alternatives in the context of existing and projected market conditions are developed.

KPL's rate increase proposal gives the Company the benefit of regulated treatment through including the costs of the plants in rate base or purchased power expenses. However, the Company proposal also provides shareholders with the benefit of merchant income because ratepayers receive virtually no credit for increased off-system sales revenues or reduced purchased power costs from operation of the plants. My adjustments titled "energy value" to Gordon Evans and Stateline allocate the benefits of energy operation to ratepayers associated with capital costs of capacity that is paid for by ratepayers. My adjustment for removing capital costs associated with dual fuel capability removes costs that KPL incurred to add flexibility to the Gordon Evans plant so that it can operate on either oil or gas, again because merchant benefits from these features are not credited to ratepayers. The dual fuel capability involves price stability rather than physical reliability associated with "keeping the lights on."

Q. Describe differences between ratepayer and shareholder interests regarding merchant treatment for the new plants?

A. To illustrate differences in economic interest between ratepayers and shareholders with respect to merchant treatment, pretend that managers at KPL are assessing whether their shareholders would be better off if the new plants are treated on a merchant or regulated basis once the plants became operational. Suppose managers believe that market clearing prices will be at levels that are high enough so that more value can be created from selling power on a merchant basis than the incremental value[1] than can be realized from increasing regulated rates. In this situation, the managers, acting as they should in the best interests. of their

[1] In this context, value is the net present value of future cash flows adjusted for differences in risk between alternatives.

shareholders, will advocate merchant treatment. On the other hand, if the KPL managers believe market prices do not provide as much value as can be realized through regulated treatment, then, again acting in the best interests of their shareholders, they should advocate for the regulated approach. In terms of the hypothetical decision faced by KPL managers with respect to regulatory treatment of the new units, the interests of shareholders are diametrically opposite from the interests of ratepayers. When market clearing prices are high enough to provide economic profit[2] on merchant plants, rates would be lower if the plants receive rate base treatment. Conversely, if market prices do not generate value above the amount that can be earned under rate base regulation, ratepayers are better off if power is purchased from wholesale markets.

The divergence in interests between ratepayers and shareholders with respect to merchant treatment of the plants is simple and direct. There is no magic regulatory scheme that can increase value to both ratepayers and shareholders by somehow reducing risks. If regulated treatment is better for shareholders, then it is worse for ratepayers. The divergent interests are more stark if partial merchant treatment and partial regulated treatment is applied over the life of a plant. Managers then have an incentive to apply treatment for portions of a plant life that is opposite from the interests of ratepayers.

Q. How does the difference between ratepayer and shareholder interests with respect to merchant treatment affect your adjustment for levelization of the Stateline capital costs over a lengthened time period?

A. KPL proposes regulated treatment for the Stateline combined cycle plant for the first part of the plant's life and undefined treatment after the seven year purchased power contract expires. By truncating the contract after seven years and computing a levelized rate in nominal dollars without reflecting expected inflation using revenue requirements from the first seven years, KPL collects a disproportionate amount of the capital costs in early years of the plants life.

[2] Economic profit is return earned over and above the cost of capital.

Indeed, KPL recovers 67% of the capital costs even though the seven year lease covers only 20% of the plant's life. If wholesale market prices are relatively high when the seven year lease term expires, KPL could realize high value from the merchant treatment option because so much of the capital costs have already been recovered. My adjustment to use levelized capital cost of Stateline over the life of the plant and inflation in the capital costs protects ratepayers paying a disproportionate amount of the capital costs of the plant without receiving associated benefits.

Q. If KPL applied merchant treatment to the new plants, how would the rate increase proposal be affected?

A. After making all of the adjustments I described above, ratepayers would be better off it the plants receive merchant rather than regulated treatment. If merchant treatment were used for all of the capacity, the KPL rate filing would be reduced for elimination of the capital costs associated with the new units. KPL would not include return on rate base, depreciation expenses, and operating expenses for the three Gordon Evans combustion turbine units. Furthermore, KPL's adjustment to purchased power expense and its adjustment to transmission expense for the Stateline combined cycle plant would be removed.

Q. Do KPL's shareholders and ratepayers have the same interests with respect to risks and cost tradeoffs with respect to purchased power expense and off-system sales revenues?

A. No. Risk can generally defined as variation in cash flow – the greater the variation the greater the risk. For electricity generation, the fluctuation in cash flow associated with an investment or a purchase power agreement is driven by physical characteristics of plants and the terms of contracts as well as wholesale market prices. Regulatory policy can increase or reduce cash flow variation to shareholders and ratepayers, but the policy does not affect the total amount of risk resulting from an asset. This means that if KPL shareholders avoid risks through a particular regulatory treatment, the risks are by necessity allocated to ratepayers.

Because risks are allocated and not avoided through regulatory policy, risk allocation can result in significant differences in interests between ratepayers and shareholders.

KPL witness Mr. Thomas Greenan suggests that limiting risks of power market fluctuations is advantageous to ratepayers: "It is important, however, to limit dependence on the wholesale market to reliably meet our retail customers' needs, which is why we are adding new generation." (Greenan testimony, page 14 at line 8). He further states that "limiting dependence on the wholesale power market . . . ultimately helps protect our retail customers from price and reliability risks inherent in today's wholesale electric market." (page 14, line 9). In fact, these purported "protections" primarily reduce risk for shareholders rather than ratepayers. This implies that additional costs related to "risk protections" should not be incurred by ratepayers.

Divergent interests with respect to risk allocation are important in this case because KPL does not have a fuel adjustment clause. Since shareholders incur risks of variation in the cost of purchased power from test year levels, the Company has a strong incentive to lock-in costs even if fixing power prices increases the overall level of cost that is likely to occur. On the other hand, ratepayer interests are to achieve the lowest cost of purchased power used in setting rates. Building capacity and fixing fixed costs rather than accepting spot price risk is an example of differing shareholder and ratepayer interests. Another example of differing interests involves the dual fuel firing capability of the Gordon Evans combustion turbine units. The benefits of dual fuel capability involve market exposure in different oil and gas price environments rather than physical capacity availability. These benefits are related to energy generation and they flow to shareholders rather than ratepayers because KPL does not have a fuel adjustment clause.

Q. How does filing infrequent rate cases affect shareholder and ratepayer interests?

A. As KPL proudly reports, rate cases have been infrequent in the past decade, unlike the 1970's and early 1980's when rate cases occurred on a more regular basis. In the past, when rate cases occurred on a more regular basis, if KPL's costs were relatively high in the test year, this would be rectified when the next case was filed. However, with less frequent rate case filings, KPL now has an incentive to file rate cases when accounting costs are at their highest levels – when power plants are new fuel costs are high and revenues earned from off-system sales are low. Higher costs that exist in early years of a plant's life can be termed "front-end loading" because revenue requirements for a single asset decline as the plant ages. If rates are established using the first year revenue requirements as the new plants depreciate, returns earned by the company will exceed the allowed return because of rate base declines with the accumulation of depreciation and deferred income taxes.

Q. How does the increased importance of off-system sales in recent years affect differences between ratepayer and shareholder interests?

A. Review of Western's financial reports illustrates the importance of off-system sales to the financial performance of the Company. The increased importance of wholesale markets means that when changes in power supply resources occur, KPL will have an incentive to understate impacts of future increases in off-system sales. In the present case, the new plants will allow KPL to increase its off-system sales. However, the Company has not adjusted its proposal to reflect these sales. My adjustments to reflect energy value of the new plants in rates results in a more equitable treatment of off-system sales.

Q. How does the changing structure of transmission affect ratepayer and shareholder interests?

A. Traditionally, transmission has been a cost of service item where transmission plant in service and transmission operation and maintenance expenses were

normal components of the revenue requirement. With the advent of open access and development of regional transmission organizations, KPL realizes significant revenues due to wheeling for third parties. Changes in the structure of transmission tariffs can also have significant impacts on revenues earned from off-system sales and on the costs of purchased power. In representing the interests of its shareholders, KPL has an incentive to include increases in transmission expenses without also including the beneficial effects of more profit from off-system sales and reduced purchased power costs. The adjustment I propose to reduce KPL's proported increase in transmission costs associated with the Stateline plant is driven in part by these differences in retail ratepayer and shareholder interests. The choice of KPL management to procure power from a plant located outside of its service territory has potential benefits as well as costs as does the choice to place retail load under the SPP regional transmission tariff.

Q. How do KPL's interests differ from ratepayer interests with respect to depreciation rates on generating plants?

A. Depreciation expense allocates the cost of a capital asset over the expected useful life span of the plant. In the past, if the capital cost was allocated over a time period shorter than the life of a generating plant, rates in the early part of the plants life would have been too high, and rates in the latter part of the plant's would have been too low. In the current environment where it is possible that generating plants will eventually be de-regulated, rapid depreciation reduces the exposure of a company such as KPL to book losses when the assets are transferred to competitive market pricing. Therefore, in the current environment, the policy on depreciation rates for generating plants involves differences in interests between shareholders and ratepayers rather than differences in interests between different "generations" of ratepayers. Shareholders have an economic interest to implement high depreciation rates on generating plants while ratepayers are better off with low depreciation rates.

The adjustment I suggest for depreciation on the Gordon Evans unit reflects a life span that is consistent with the actual experience of other combustion turbine units owned by Western. For these units, Western has used a depreciation rate that, with hindsight, has been too high because the plants have significant remaining life but no associated book value. Even though the historic depreciation rates have been too high for its turbines, KPL proposes a useful life of 25 years for the new Gordon Evans units. My adjustment for depreciation on the new Gordon Evans combustion turbine units applies a depreciation rate that is more consistent with the actual experience of Western.

Section VI:

<u>Energy Profit Margin Earned by the New Plants</u>

Q. Describe the term energy margin as you use it in your testimony?

A. For most hours of the year, utility companies such as KPL either purchase power from other wholesale entities or they sell power on an off-system basis. Therefore, whenever KPL operates a plant, the energy it produces either displaces purchased power or alternatively, the energy allows the Company to make additional off-system sales. This is true even if the Company suggests that energy from a plant is dedicated to retail ratepayers and even if the Company suggests that the capacity covers growth in load.

To illustrate this fact, assume three power plants are running in an hour, and the first two generate energy equal to retail load while the third sells into wholesale markets on an “off-system” basis. If the first or second unit were not operating, the third plant could not make off-system sales. Protestations that the first and second plants only serve retail load and therefore are not impacted by wholesale power prices are not correct. Furthermore, sales growth in general produces a positive financial margin because retail rates are above variable operating costs. Therefore, retail sales growth provides benefits to shareholders and assertions that every value should not be reflected because of growth are incorrect.

The market-clearing price of power drives the value of both purchased power and off-system sales. In addition, a generating plant should only operate when the incremental cost of running the plant is below the market-clearing price of power. If the price of power is above the variable cost of running a plant (the fuel expense and variable operation and maintenance expense), and KPL is purchasing power, then KPL can save money by operating the plant and purchasing less power. If the price of power is above the variable cost of a unit and KPL is making off-system sales, KPL can increase profits by running the plant and selling more power. I label the increased off-system sales or decreased purchased power cost as "energy margin."

The formula for energy margin from a generating plant in an hour can be defined as:

Energy margin/MWH = Market Clearing Price/MWH – Variable Cost/MWH

This margin is earned in hours when the plant operates, and it is zero when the plant does not operate. Once the energy margin is computed for an hour, it can be summed over all of the hours in the year to determine the total energy value per megawatt per year. With data on the energy value per MW/Year, total energy value can be calculated through multiplying the figure by the capacity of the plant. A final factor that should be considered is the fact that generating plants may not be available to produce energy because of maintenance outages.

Q. How has KPL treated the energy margin earned from the Gordon Evans units in its rate increase proposal?

A. For the Phase 2 portion of the project that is expected to be placed in June, 2001 (154 MW), the Company proposes to retain all of the profit the Company earns from the energy margin for its shareholders. In the case of the two units that were placed in service in the summer of 2000 (160 MW), KPL has implicitly included

fuel cost and energy generation using the actual partial year of operation of the plant from June 1, 2000 through September 30, 2000. However, the Company makes no adjustment for the full year energy value of the unit. For example, according to KPL witness Mr. Thomas Greenan, “From commercial operation through October 3 1, 2000, we ran one of the new combustion turbine units for parts of 78 different days and the other for parts of 68 different days.” (Greenan testimony, page 13 at line 14). Therefore, for the test year period October 1, 1999 through May 3 1, 2000, no energy margin on Phase 1 of the Gordon Evans units is provided as a benefit to ratepayers.

Q. How has KPL treated the energy margin earned from the Stateline purchased power contract?

A. As with the Phase 2 of the Gordon Evans combustion turbine that is expected to begin operation this summer, KPL retains all of the energy value from the 200 MW Stateline purchased power contract for its shareholders in the rate filing. That is to say, ratepayers get no credit for any energy margin resulting from the Stateline plant.

Q. How should the energy margin earned by the new plants be treated on an equitable basis to ratepayers and shareholders?

A. The appropriate ratemaking treatment depends on how capital recovery is handled in the rate case. If, as KPL proposes, ratepayers fund capital recovery of new plants through return on rate base for Gordon Evans and through purchased power charges for Stateline, the energy cost savings associated with generation from the plants must be credited to ratepayers. On the other hand, if merchant treatment is applied to the capacity wherein ratepayers do not pay for capital recovery in retail rates, shareholders rather than ratepayers should retain the energy margins. The problem with KPL’s proposal is that the shareholders receive both the energy margin and recovery of capital costs.

In order to adjust KPL's rate increase proposal so as to reflect a more equitable treatment for ratepayers, I have computed energy margins for the new plants and for the Jeffrey Energy Center. (The reason I also compute margins from the Jeffery Energy Center is to quantify the impacts of KPL's capacity sale to Empire, in which the Company sells energy at the fuel cost of the Jeffrey Energy Center rather than at the market-clearing price of power.) I have calculated the energy margin for the calendar years 1998, 1999 and 2000 as well as for the test period October 1, 1999 through September 30, 2000. In addition, because of the partial year operation of Gordon Evans and the partial year impact of the Empire capacity sale, I have separated the energy margins for the test year into the period October 1, 1999 through May 3 1, 2000 and the period June 1, 2000 through September 30, 2000.

Q. What historic data on the market clearing price of power have you used to compute energy margins?

A. As is apparent from the above formula for computing the energy margin per hour, it is necessary to have data on both market prices and the variable operation costs of generating plants. In order to make the calculation, I have used the following sources of data for market prices:

1) Daily market clearing prices for the northern SPP region published by Power Markets Week for the period 1998 through 2000; and,

2) Hourly market price data for interchange sales and purchases provided by the company for 1998-2000.

Q. How have you determined the variable costs for purposes of computing energy margins?

A. To establish the variable cost per MWH of generating resources required for computation of energy margin, I have used information on average heat rates of the units, data on natural gas prices, estimated variable operation and maintenance

per MWH and the actual historic fuel cost per MWH of operating the Jeffrey Energy Center. The formula for variable cost can be stated as:

Variable cost / MWH = Heat Rate x Cost/MMBTU + Variable O&M/MWH

I have assumed an average heat rate of 7,860 BTU/KWH for the Stateline plant and an average heat rate of 12,000 BTU/KWH for the Gordon Evans units.

In computing the fuel cost per MWH of the new plants, the heat rate must be multiplied by the natural gas price per MMBTU. I have used monthly data on natural gas prices delivered to electric utilities in Kansas published by the Energy Information Agency to develop this part of the calculation. For the Jeffery Energy Center, I have used actual monthly fuel cost per MWH that the Company presented in response to question KGE 067 submitted by the Kansas Industrial Consumers.

Q. **What assumptions have you made with respect to reducing energy margins to reflect maintenance outages of generating plants?**

A. The factors used to reduce the energy margin that is computed for each hour of the year should be different for different types of generating plants. In the case of plants such as the Jeffrey Energy Center, with low fuel cost and high capacity factors, the factor to reduce energy margins should approximate the plant availability because the plant produces value for the vast majority of hours in which it is available. For plants that operate less frequently such as the Gordon Evans combustion turbines, planned maintenance should occur at times when the plants would probably not have been dispatched against market prices. Therefore, in the case of plants with relatively high variable cost, such as Gordon Evans, the factor used in reducing energy margins should be less than the generating plant availability factor.

For the Jeffrey Energy Center, I reduce the energy margin by the 15% assuming an availability factor of 85%. For the Stateline plant, which has higher fuel costs than the Jeffrey Energy Center, but lower costs than steam units fired by natural gas and peaking plants, I reduce the energy value by 10%. In the case of Gordon Evans plant with relatively high fuel costs and less frequent dispatch, I use a factor of 5% reflecting the ability to perform maintenance when the plant would not have operated on an economic basis.

Q. How much energy value did the Jeffrey energy center produce and how much energy value would the new plants have generated during the test year?

A. The calculation of energy margin results in an amount of profit on a per megawatt hour basis where the variable operating cost per MWH is subtracted from the market price per MWH. When the calculation is summed over the number of hours for the year, the calculation yields a figure expressed in terms of dollars per megawatt per year. Dividing this number by 1,000 expresses the energy value on a $/kW/Year basis. I believe this is an effective way to present the energy margin data because the demand charge represents capacity costs that constitute capital recovery can also be expressed in terms of $/kW/Year.

The table below summarizes my calculation of the energy margin produced by Gordon Evans, Stateline and the Jeffrey Energy Center for various time periods. I present tables using both the Power Markets Week data and the Interchange Pricing data provided by the Company. For the Power Markets Week data, I separate the energy margin earned during on-peak and off-peak periods. As expected, because of the differences in variable cost, the energy margin per KW/Year is highest for the Jeffrey Energy Center and it is lowest for the Gordon Evans combustion turbine units.

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The reason energy margins are higher in 1998 and 1999 than in the test year is because of higher market prices relative to the price of natural gas.

The data in this table also demonstrate that since KPL is a net seller in wholesale markets, low market prices in the test year are unfavorable to ratepayers and the relatively low prices are favorable to shareholders. Stated differently, because KPL sells more power than it purchases, if higher market-clearing prices had been used both for purchased power and for off-system sales, KPL's revenue requirements could have been reduced. However, I have not made an adjustment to reflect this fact.

Q. How have you used the energy margins expressed in $/kW/Year to develop dollar adjustments for purposes of the revenue requirement calculation?

A. Once the energy margin calculation is made on a $/kW/Year basis, the total dollar number can be established through multiplying that number by the capacity of the plant. (I note that for the Gordon Evans combustion turbine units and the Stateline plant this number is somewhat understated because the winter capacity is generally greater than the summer capacity for these types of plants.) The product of energy value per kW per year and the capacity of the plants used for making the energy margin dollar adjustment is presented in the table below. I

have used the market prices from Western's interchange sales and purchase transactions. These numbers correspond to the dollar amount of the adjustments on a total company basis presented in Schedule __ ECB-1.

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Q. How do increases in natural gas prices affect the calculation of energy margins generated by the new plants?

A. Increased natural gas prices will increase the fuel cost on both the Stateline plant and the Gordon Evans combustion turbine units. However, since the increased natural gas prices also increase the cost of running other units such as the Gordon Evans steam units, the higher natural gas prices also increase the overall market price of power. During those hours when the Gordon Evans combustion turbine units and/or the Stateline plant operates, the market price will be driven by electric generating plants that have a higher cost than these units. Most probably power plants that drive market prices during periods when the Gordon Evans combustion turbines and Stateline are running will not be fired by coal. Therefore, when the new Gordon Evans and Stateline plants operate, if the natural gas price is higher than historic levels, the market price will be increased more than by the variable costs of Gordon Evans and Stateline, and energy margin will increase. Therefore, if increased natural gas prices are included in the energy margin analysis, the energy value should be increased and the adjustment would be even higher.

KPL proposes to increase revenue requests associated with higher fuel expense for its natural gas energy produced. However, the higher natural gas prices also mean that market prices are higher and KPL will earn more profit on off-system

sales. Indeed, one could argue that a downward adjustment in net costs appropriate to reflect higher gas prices. However, I have not made this adjustment.

Q. How is the energy margin affected by alternative assumptions with respect to heat rates for the new units?

A. I understand that KPL has stated in a presentation to financial analysts that the heat rate on Stateline is 7,000 BTU/kWh. Further, I understand that the average heat rates on new combustion turbine units can be in the range of 10,500 BTU/kWh. Using these assumptions, the energy value for the new units increases almost $3 million as demonstrated in the table below.

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Section VII:

Depreciation Rate Adiustment for the Gordon Evans Combustion Turbine Units

Q. How has KPL computed depreciation on the Gordon Evans combustion turbines for purposes of developing its rate increase proposal?

A. In presenting its adjustment for cost increases associated with Phase 2 of the Gordon Evans project, KPL shows additional depreciation expense of $3.084 million on a KCC jurisdictional basis. Using the proposed KCC jurisdictional cost basis for Phase 2 of $61.3 million, this implies a depreciation rate of 5.03%. Applying the same depreciation rate to the Gordon Evans Phase 1 cost of $64.2 million results in depreciation expense of $3.23 million. For all three of the

Gordon Evans combustion turbine units, the depreciation expense amounts to $6.3 million using the 5.03% depreciation rate. While the $3.084 million is presented for the Gordon Evans Phase 2 adjustment, the depreciation rate recommended by KPL witness Mr. James Aikman is 4.20% (see page 4 of Aikman testimony). (The difference between the 5.03% rate and the 4.20% rate is presumably a component of the depreciation study adjustment.) Using the 4.20% depreciation rate and the plant in service for Phase 1 and Phase 2 of the plants rather than the 5.03% rate reduces depreciation expense for Gordon Evans on a Company wide basis by $1.042 million to $5.258 million. The total revenue requirement for Gordon Evans presented in Schedule ECB-1 uses depreciation expense assuming the 4.20% rate rather than the 5.03% rate.

In explaining the 4.20% rate, Mr. Aikman explains that he uses the "life span, forecast method." (see page 10 of Aikman testimony). Further, he states that he bases his analysis in part on "an evaluation of the life history of comparable plant and equipment" (see page 23 of Aikman testimony). If the residual value of the plant is negative 5%, the life span implied by a 4.20% rate for Gordon Evans is 25 years.

Q. Is a life span of 25 years for the new Gordon Evans combustion turbine units reasonable?

A. No. The projected life span of existing combustion turbine units owned by Western is more than 25 years. The Company has a number of plants that are about 25 years old and the KPL's analysis of future load and capacity does not project any retirements in the next ten years. Therefore, the life span of Western's existing combustion turbine plants is at least 35 years.

Q. Describe your adjustment to the depreciation expense on the new Gordon Evans combustion turbine plants that is more equitable for ratepayers?

A. I have used a 35 year life span and no residual value to determine a reasonable level of depreciation. I have not used the negative residual value assumption

because under the terms of the "ground lease" between KPL and KGE,

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Section VIII:

<u>Appropriate Capital Costs for the Gordon Evans Combustion Turbines</u>

Q. What capital cost level is appropriate for inclusion in rate base for the Gordon Evans plants?

A. If the new Gordon Evans plant receives traditional rate base treatment, only reasonable costs that are associated with ratepayer benefits should be included in the rate base. As has been the case for new generating additions that have been placed into service in the past, ratepayers should not pay unreasonable or imprudent costs.

Q. Has the Company presented evidence that its expenditures for the new Gordon Evans combustion turbine units are reasonable?

A. Yes. The Company hired a consultant, Ms. Natalie Roth, to present a comparison of the cost of Gordon Evans and Stateline to other plants. Ms. Roth asserts that "the current cost estimates for each of the three KPL combustion turbine units are reasonable and certainly in a comparable range with the cost of similar units nation-wide" (Roth testimony at page 10). She argues that the cost per kW of $407/kW for Phase 1 of the project – "Class E Simple Cycle Combustion

Turbines" -- should be compared with three plants that have costs of $325/kW, $388/kW and $380/kW respectively. Gordon Evans Phase 1 exceeded the average cost of these three units -- $364/kW -- by 11.7%. However, Ms. Roth adds $70/kW to each of the three plants to arrive at her comparison base of $390/kW to $450/kW. The added cost of $70/kW is derived from the amounts KPL experienced for "Reliability Costs" -- $45/kW – and for "Owner costs and AFUDC" of $25/kW. The location of these three comparison plants is not specified; whether the plants use an existing site is not specified; actual owner and AFUDC costs of the plants are not specified; and the summer versus winter capacities are not specified.

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KPL justifies the cost of Phase 2 of the Gordon Evans project with a similar comparison of three other plants. These plants had a cost of $325/kW, $330/kW and $324/kW respectively. Ms. Roth adds $53/kW to the cost of these plants for "Reliability" and "Owner Costs and AFUDC" using the same approach of adding those Gordon Evans cost items that she applied for the Phase 1 comparison. After making the adjustments, the three comparison plants had a average cost of $380/kW which compares to the Gordon Evans Phase 2 cost of $390/kW. As with the Phase 1 comparative analysis, the location of these three plants is not specified; whether the plants use an existing site is not specified; actual owner and AFUDC costs of the plants are not specified; and the summer versus winter capacities are not specified.

Q. Is KPL's comparative analysis adequate to justify that expenditures for the new Gordon Evans combustion turbine units are reasonable?

A. No. The cost comparison must be adjusted for regional differences in labor costs and the comparison should account for differences in owner costs and plant sites. For example, the cost KPL experiences for the plant site is included a "ground lease agreement" between WRI and KGE. The cost is accounted for as an operating expense rather than a capital item.

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My rationale for the adjustment that reduces KPL costs for the ground lease recognizes that comparison with units such as KCPL's Hawthorne should be on a basis that includes the ground lease. Since KPL's comparison did not include the ground lease, the cost should not be paid by ratepayers.

Q. How does KPL justify additional expenditures the Company has incurred for dual fuel capability and fuel oil inventory?

A. The Company acknowledges that capital costs associated with dual fuel capability result in a cost for Gordon Evans that is above costs experienced by "merchant power developers who invest in reliability only to the point of diminishing business returns" (see Roth testimony at page 7). KPL quantifies the "reliability costs" as $7.187 million for Phase 1 and as $3.436 million for Phase 2. Costs of dual fuel firing excluding costs of the diesel generator and costs of the water treatment building are $3.468 million for both Phase 1 and $3.436 million for Phase 2. In addition, the Company adds $600,000 in fuel oil inventory costs to the rate increase proposal. Ms. Roth asserts that dual fuel capability is necessary because of "price stability and reliability of supply" issues associated with times

when “natural gas is curtailed to supply home heating demands or is otherwise unavailable” (see Roth testimony at page 7).

Q. Under KPL’s proposal, do ratepayers receive benefits associated with expenditures for dual fuel capability that KPL has made to achieve price stability?

A. No. Without a fuel adjustment clause, KPL’s shareholders realize both costs and benefits from variation in the wholesale market price of power. With the dual fuel capability option, KPL’s shareholders can benefit through reducing exposure to spikes in the price of natural gas. On the other hand, because of the manner in which KPL has computed fuel expense, purchased power expense and off-system sales for purposes of the rate case, ratepayers receive no benefits from the dual fuel option in terms of fuel savings. During the test year ended September 30, 2000, the Gordon Evans Units did not bum oil and therefore there was no impact on fuel expense, purchased power expense or off-system sales from exercise of the dual fuel option. In sum, any benefits from dual fuel capability have not been credited to ratepayers.

The manner in which shareholders benefit from their option to burn oil with dual fueled capability is illustrated by events that happened this winter. After September 30, 2000, the two Gordon Evans units in service did in fact exercise their option to burn oil instead of natural gas, presumably because of the very high gas prices. However, no benefits from the substitution of oil for natural gas to ratepayers exist in the case because the oil option was only used after the test year. If ratepayers receive no benefit from the dual fuel firing capability, they should not be burdened with the additional capital costs.

Q. Have you accounted for the benefits associated with dual fuel capability in your analysis of the energy value generated from the Gordon Evans plants?

A. No. My analysis of energy value presumes that the units only burn natural gas. Therefore the energy value adjustment does not give ratepayers credit for

additional value that the units can generate through exercising the option to burn oil.

Q. Do ratepayers receive benefits from dual fuel capability through increased reliability of supply at times when natural gas is curtailed in order to supply home heating demands?

A. I doubt it. System reliability of generation involves the possibility that total generation capacity will not be sufficient to meet total demand. Physical reliability (as opposed to reduced expense to price volatility) involves the probability that system-wide generating capability will not be sufficient to meet total load. KPL is a summer peaking utility company and natural gas is rarely curtailed in the summer time. Furthermore, since the region is also summer peaking, there are abundant supplies of power on the market in winter. In sum, it is unlikely that dual fuel capability is necessary for physical reliability. If dual fueling is valuable, that value arises from mitigating price volatility rather than reducing the probability of aggregate system outages. Therefore, the benefits of dual fuel firing are related to energy production options and accrue to shareholders rather than ratepayers.

Q. How have you adjusted capital costs of the Gordon Evans plant in order to reflect a more equitable treatment for ratepayers?

A. I have removed added capital costs associated with dual fuel capability and I have removed costs of the ground lease that were not considered in the Company's comparative cost per KW analysis. The asserted reliability features are approximately $3.468 million for Phase 1 and are approximately $3.436 million for Phase 2. In addition, the fuel inventory increase of $600,000 arises because of the plant's dual fueling capability.

I emphasize that removal of these costs does not imply that KPL has been imprudent in making the expenditures. Rather, the adjustment fairly allocates

costs to shareholders when shareholders rather than ratepayers receive benefits of those expenditures.

I have removed the cost of the ground lease agreement because KPL's assertion of reasonable costs is derived from cost comparisons without the ground lease. If the ground lease is included as an operating expense, KPL's Gordon Evans costs are above costs per KW of the small sample the Company uses to make its comparison. More importantly the cost per KW of Gordon Evans including the ground lease is far above the cost per KW of KCPL's plant at the Hawthorne site.

Section IX:

<u>Adiustment for Capital Recoverv Costs Associated with the Stateline Purchased Power Contract</u>

Q. How does KPL propose to charge retail ratepayers for recovery of capital costs of the Stateline plant?

A. KPL computes revenue requirements associated with Stateline capital costs of $108,562,656 for depreciation expense, income taxes, return on rate base, Missouri franchise costs, insurance costs and property taxes. These revenue requirements are calculated each year for the first seven years of the life of the Stateline plant. KPL then determines the present value of the first seven year revenue requirements. Once the present value is established, KPL computes a level annual payment through dividing the present value by an annuity factor such that the level payment yields the same present value as if the year by year revenue requirements were received. The levelized payment results in an annual cost of $17.26 million per year over a seven year period using KPL's cost of capital and capital structure assumptions which include a return on common equity of 12.5% and a capital structure made up of 50% debt and 50% equity. In addition, KPL proposes to charge ratepayers for the variable operation and maintenance costs of $220,752 associated with the Stateline contract that is derived from assuming that the plant operates at a 60% capacity factor.

Q. What percent of the present value of Stateline costs does KPL recover over the seven year lease term?

A. KPL recovers 67% of the plant costs over the seven-year term. If the plant life is assumed to have a life span of 35 years, the term of the lease covers only 20% of the plant's life. I have computed recovery of capital costs by using KPL's approach and extending the analysis for a period of 35 years. To extend the analysis, I applied MACRS tax depreciation rates and continued the inflation assumption of 3% inflation on insurance costs made by the Company for the initial seven years. KPL computes the present value of revenue requirements over the seven-year term of the lease as $95.284 million. This is the amount that KPL uses in order to establish the levelized payment of $17.256 million. When the same calculation of present value of revenue requirements is made over a thirty-five life, the present value sums to $141.25 1 million. Dividing the $95.284 million by the $141.251 million implies that KPL's level payment recovers 67% of the total lifetime present value of revenue requirement.

Q. Why does recovery of 67% of the Stateline capital cost provide KPL shareholders with disproportionate benefits compared to ratepayers?

A. If Westar recovers 67% of the plant costs over the seven year term and realizes profits on a merchant basis for the remaining 28 years (assuming a 35 year plant life), Westar will realize more value than other merchant developers can realize and ratepayers will incur higher costs than if the plant were either regulated over its entire life or treated on a merchant basis over its entire life. The high proportion of capital recovery occurs because the first seven years of the plant's life have a higher revenue requirement than the later years and because KPL does not consider inflation in levelizing costs. The issue is particularly important because the plant may earn revenues on a merchant basis in the later portion of its life.

Q. Describe your computation of a more equitable method for capital recovery?

A. I have computed a more equitable treatment of the capital recovery of Stateline presuming that the plant may eventually receive profits on a merchant basis. This

approach computes an amount in real inflation adjusted dollars that is the same for each year of the assumed thirty-five year life. In nominal terms, the dollar amount of annual recovery increases at 3% per year. After making this adjustment, instead of being $17.256 million, the first year capital recovery amount is $10.38 million. In other words, the amount of $10.38 million per year escalated at 3% yields a present value that is the same as the present value of revenue requirements over the 35 year life. For purposes of the rate case, I use the average nominal dollar capital recovery rate over the first four years of the plant's life. The average payment amount of the capital recovery is $10.857 million using this approach. After allocation to retail ratepayers, the adjustment reduces revenue requirements associated with Stateline by $5.918 million on a KCC jurisdictional basis (or $5.519 million on a total Company basis).

Q. Does the annual amount that you compute for capital recovery change if the Commission changes KPL's assumed capital structure and return on equity assumptions?

A. Yes. With a lower cost of capital, the capital recovery amounts associated with Stateline change significantly. A lower cost of capital lowers the revenue requirements that are the basis for capital recovery and the lower cost of capital implies that more costs are recovered in the later years of the life of the Stateline plant. I emphasize that my presentation is in no way intended to be an endorsement of the KPL proposed cost of capital or the capital structure that is the basis for its calculation of the levelized revenue requirement. Instead, I recommend that the Commission should compute the level real revenue requirement over the life of the plant using the final cost of capital and capital structure that is deemed appropriate.

Q. Why have you removed the variable operation and maintenance charge portion of purchased power expense that KPL proposes to recover for the Stateline plant?

A. In computing the energy margin from the Stateline plant, I subtract the variable

operation and maintenance costs along with the fuel costs. Therefore, the variable operation and maintenance costs are already reflected in the adjustment. If the variable operation and maintenance costs were not subtracted in computing the energy margin, the adjustment would be greater. I have excluded the $220,752 in order to be consistent with my method for computing energy margin.

Q. Does the manner in which annual you compute capital recovery amounts mean that you agree that KPL's cost associated with the Stateline plant is reasonable?

A. **No.** KPL attempts to justify the dollar capital cost of Stateline through comparisons with the cost of other new combined cycle plants. KPL's witness Ms. Natalie Rolph concludes that the cost of the Stateline plant of $527/kW is reasonable compared to other plants that had a cost range of between $490/kW and $570/kW. However, the efficiency of the Stateline plant is worse than the efficiency of other new combined cycle plants in part because of use of an existing Empire steam unit. The heat rate of the plant is about 7,860 BTU/kWh which compares to about 7,000 BTU/KWH for other new units (the higher the heat rate the worse the efficiency of the plant). Further, the cost of Stateline is affected by the regional labor costs and the fact that the plant is being constructed on a site with an existing generating plant. The manner in which KPL presented its comparative data on other plants does not allow me to make adjusted comparisons.

An adjustment to the cost of Stateline may be warranted through an appropriate comparison with other plants that incorporate the effects of use of an existing steam generator, the geographic location of the plant and the fact that the plant is built on an existing site.

Section X:

Transcription Costs

Q. How has KPL treated transmission costs in its rate increase proposal?

A. KPL allocates 78% of transmission plant in service, operations and maintenance costs and transmission depreciation expense to retail ratepayers and it does not give retail ratepayers credit for wheeling revenues it receives from third parties. In addition, KPL makes an adjustment of more than $3.5 million for its estimated costs of moving retail load to the SPP regional transmission tariff. KPL attributes $3.371 million of the transmission increase directly to jurisdictional operation of the Stateline Plant. This transmission adjustment equates to a cost of $1.57/kW/Month for the Stateline capacity. In explaining this adjustment, Mr. Richard Dixon, Western Resources' Vice President of transmission services, states: "In connection with placing the State Line Combined Cycle generating facility in service, KPL will incur charges of $3,770,338 for firm point-to-point transmission service to move the SLCC power from the plant to KPL's control area. By placing its retail load under the regional tariff and designating SLCC as a network resource, KPL will be able to move power from all of its network resources, including SLCC, to its load centers using the network tariff without taking point-to-point service. As a result, rather than paying $3,770,338 just to move the SLCC power to its load centers, KPL will be able to move that power and receive all its other transmission service from SPP for $3,541,419." (Page 6 of Dixon testimony).

Another KPL witness, Mr. Kelly Harrison describes the adjustment as follows: "The adjustment also includes an annual transmission expense of $3,770,388, which represents the annual expense KPL will incur under the long-term firm transmission agreement entered into with the Southwest Power Pool to transmit the capacity and energy from the State Line CC Plant as a network resource under its open access network transmission tariff in order to transmit the capacity and energy from its border to native load customers" (Harrison page 5, line 14).

Q. Is KPL's proposed treatment of transmission reasonable?

A. No. KPL's proposed treatment imposes unreasonable costs on ratepayers and it allows shareholders to earn amounts in excess of its cost of capital associated with transmission. For reasons that I elaborate below, attribution of an additional $3.3 million in costs associated with transmission for the Stateline plant to retail ratepayers is not appropriate.

Q. Can KPL realize benefits through reduced purchased power expenses and increased off-system sales by placing retail load under the SPP regional tariff?

A. Yes. Mr. Dixon acknowledges that a benefits will arise by placing retail load under the SPP regional tariffs in his testimony: "as energy from non-firm resources located in the SPP area becomes available on an economic basis, it too may be imported without incurring additional ("pancaked") transmission charges." (Dixon testimony, page 7, line 9). However, since KPL did not make any downward adjustments to purchased power expense to reflect the lower transmission costs, the shareholders receive all of these benefits and ratepayers do not receive benefits.

Q. Has KPL demonstrated that its proposed increase in transmission cost is associated with additional plant in service and/or additional expenses associated with maintenance or operation of actual transmission facilities?

A. No. The added transmission expenses are associated with changes in the organizational structure of transmission rather than increases in physical cost. Changes in the organizational structure of transmission are generally intended to increase the efficiency of the electric power system and thereby should reduce rather than increase costs. Therefore, the notion of a increasing rates to compensate for costs associated with transmission re-structuring is questionable. Since the transmission expense increase of $3.5 million asserted by KPL is not associated with physical activities (plant in service or operations and maintenance

expense), the transmission expense increase paid by retail ratepayers involves wealth transfers to groups other than KPL retail ratepayers. These other groups could be other utility companies, and/or the SPP organization and/or FERC regulated requirements customers and/or KPL shareholders.

Q. Since KPL will move its load to the SPP regional tariff before many of the other Companies in the region, is it possible that revenues received by SPP will not be refunded to KPL?

A. Perhaps. If all companies in SPP placed their total load on the SPP regional tariff, and the physical cost of transmission did not change, the net cost of transmission on an aggregate basis to all companies in SPP should be the same or less than it was without the regional tariff. In this scenario, aggregate transmission costs have not changed and revenues received by SPP from the tariff would presumably be refunded to the individual companies (or transmission rates would be reduced) because the transmission revenues are not associated with out of pocket costs incurred by the SPP organization. The aggregate net cost of transmission may even be reduced if usage on the transmission grid becomes more efficient with the regional tariff. Recall that KPL's wheeling revenues have increased very significantly in the past few years.

While the net transmission costs should not increase if all companies are on the tariff, for a "first mover," the costs of moving to the regional tariff may exceed the benefits. Before all companies place themselves on the regional tariff, revenues from the tariff may be used for SPP administrative costs and the refunds of excess SPP revenues may not match the charges on an individual company basis. This begs the question of whether KPL retail ratepayers or KPL shareholders should bear the costs of helping the regional tariff to become accepted. Since shareholders are receiving significant benefits from transmission wheeling revenues, they are in a better position than ratepayers to fund these "first mover" costs.

Q. Is it reasonable to charge higher transmission costs to KPL retail ratepayers because the Stateline plant is located outside of KPL's retail service territory?

A. No. KPL has not presented evidence that the geographic site of the plant offers retail ratepayers benefits in terms of a lower capital cost and/or improved efficiency. Further, the Company has failed to demonstrate that it could not have located a combined cycle plant within its own service territory so as to avoid the transmission cost. Finally, the geographic location of the Stateline site may offer KPL shareholders advantages that outweigh the added transmission expense. Energy from the plant may potentially be sold by KPL to the east on an off-system basis more profitably than had the plant been built within the KPL service territory. For example, entities that purchase energy from Stateline may have less physical transmission constraints and they may experience lower wheeling charges because of the location of the plant. KPL has not credited any off-system benefits of the plant location to retail ratepayers.

Section XI:
Impacts of Western's Proposal on the Efficiency of Generation Markets

Q. If KPL's rate increase proposal is accepted how would incentives for construction of the efficient amount and mix of capacity be affected?

A. If KPL could receive assured recovery of its capital costs associated with new capacity no matter how much capacity is added and no matter what type of capacity is added, the long term efficiency of generating markets would be affected in a negative way. Other developers who sell into wholesale markets on a merchant basis would not be playing on a level field. These developers earn profits depending on the efficiency of their investments both from a minimum cost standpoint and a capacity type standpoint. If one player in the market – KPL – can earn returns no matter what type of capacity is added and no matter what cost is expended for the capacity, the whole marketplace will be affected in a negative way. For example, if market prices imply that combined cycle plants are

more efficient than combustion turbine plants, and KPL receives full capacity cost recovery for construction of combustion turbine plants, the mix of capacity will not be optimal. In this scenario, wholesale market prices will also be different than they would be had the most economically efficient type of capacity been added.

Q. If KPL can choose whether to apply regulated or merchant treatment to the new plants, how is the efficiency of generation markets affected?

A. If KPL has an option to select alternative capital recovery approaches and this option is not present for other developers in the market, regulation has created an advantage for one company. This not only distorts decisions of the regulated company, but also the decision making of competitors who do not have the assured capital recovery option.

Q. How does the potential treatment of Stateline whereby the plant may be regulated during a portion of its life and it may earn profits on the basis of market prices during latter portions of its if affect market efficiency?

A. The treatment of Stateline could result in a situation where one market participant – KPL – has a lower capital recovery base than other developers who must recover all of their costs from market prices. Giving one company such a competitive advantage runs counter to the efficient development of competitive markets.

Q. Do your adjustments for energy value and other items such as the lengthed life span assumption for Gordon Evans rectify the problems of inefficiency inherent in KPL's rate increase proposal?

A. No. These adjustments create a more equitable regulated treatment, but the adjustments leave a situation where KPL is in an advantageous situation relative to other competitors in the market.

Section XII:

Ratepayer Impacts of KPL'S Capacity Sale to Empire

Q. Why is it relevant to compare the value of the new units included in revenue requirements with the value of long-term firm sales contracts?

A. If ratepayers would purchase power under the same terms as customers who secure long-term firm capacity and if this capacity has lower cost than the capacity from the new units, one could argue for a ratemaking adjustment.

Q. From the perspective of ratepayers, is it reasonable to sell power on a long-term basis at a lower cost than the cost it is imposing on retail ratepayers for the new plants?

A. No. If the long-term transactions were agreed to during a reasonably similar time frame as the decision to acquire new capacity, selling long-term firm power at costs below the cost of the new plants is an unreasonable proposition. In this situation, had the capacity that is used for the long-term sale instead been used to reduce the amount of the new capacity acquisitions, ratepayers would be better off. It is unreasonable to buy more capacity than is necessary only to sell it at below the cost of acquiring new capacity. Instead, ratepayers should expect to obtain capacity at the least net cost.

Q. Does this conclude your testimony?

A. **Yes.**